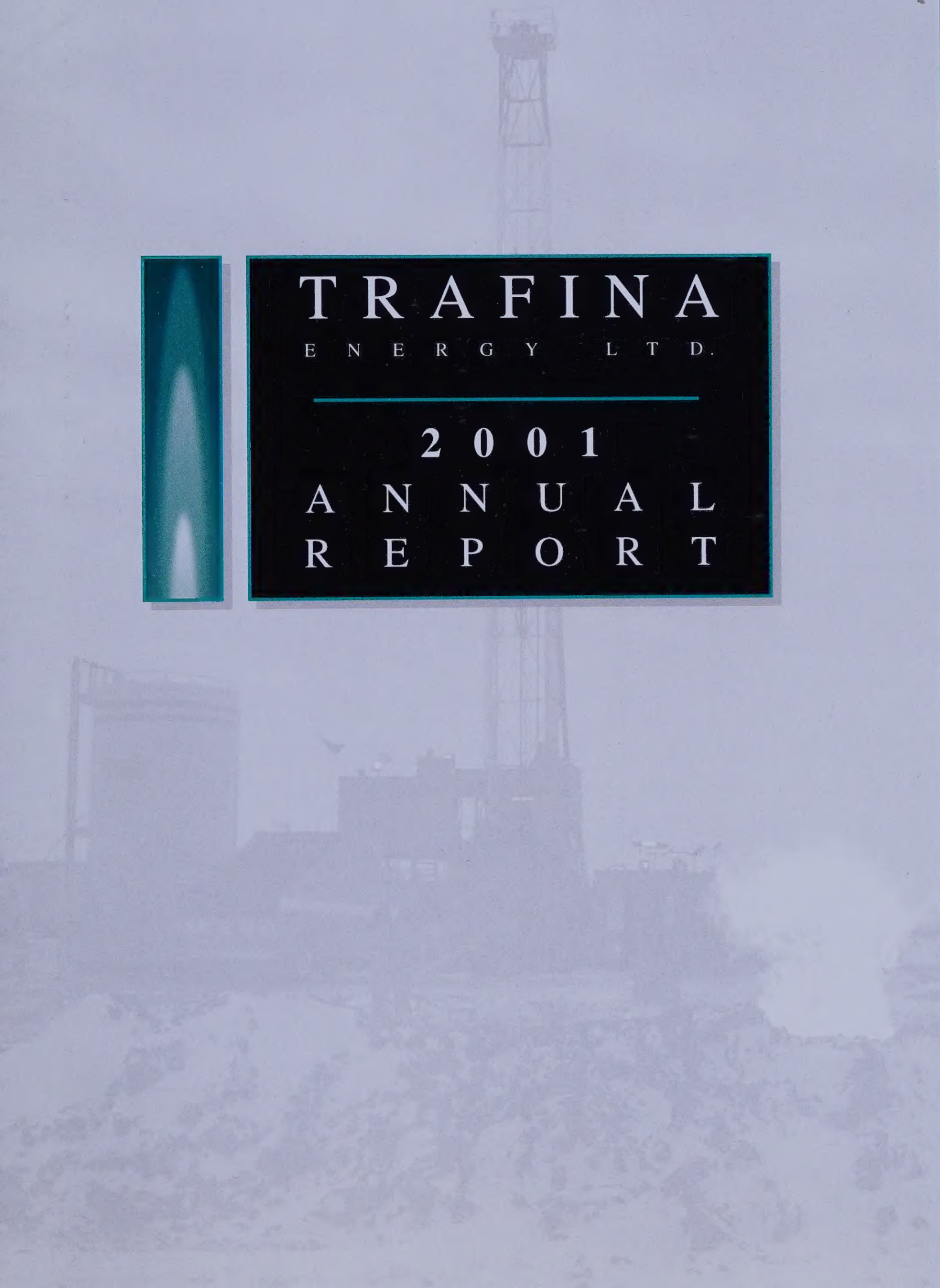


TRAFINA ENERGY LTD.

2001 ANNUAL REPORT

TRAFINA Energy Ltd.

ANNUAL GENERAL MEETING

The Annual General Meeting of Shareholders will be held on May 17, 2002, at 9:15 a.m. in the Second Floor Conference Room of 505 – 3rd Street SW, Calgary, Alberta. The Board of Directors, Management and Staff of TRAFINA welcome the opportunity to meet shareholders and interested persons. ***Shareholders unable to attend the meeting are asked to complete and return the Proxy Form mailed with the Annual Report.***

TRAFINA'S WAYS

Honesty and Integrity: *We wish to act fairly in our business dealings.*
Achievement: *We try to make our contributions to others and ourselves.*
Communication: *We try to have open and honest communications in all our workings.*
Environmental Protection: *Continually improve our processes to minimize pollution and waste.*

CONTENTS

GLOSSARY OF ABBREVIATIONS

AB	Province of Alberta
API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
Bbl	Barrel of Oil
Bbls	Barrels of Oil
Bbls/d	Barrels per Day
MBbls	Thousands of Barrels
Bcf	Billion Cubic Feet
BOE	Barrel of Oil Equivalent (gas at 6:1)
BOE/d	Barrel of Oil Equivalent per Day
M	Thousand
MM	Million
MBOE	Thousand Barrels of Oil Equivalent
Mcf	Thousand Cubic Feet
Mcf/d	Thousands of Cubic Feet per Day
Mmcf	Millions of Cubic Feet
NGL's	Natural Gas Liquids
APO	After Payout
BPO	Before Payout
GORR	Gross Overriding Royalty
NCI	Net Carried Interest
WTI	West Texas Intermediate
WI	Working Interest
psig	Pounds per square inch gauge

HIGHLIGHTS

FINANCIAL	2001	2000	% Change
Gross revenue ($)	3,017,072	2,349,667	+28
Cash flow from operations ($)	1,342,543	1,209,236	+11
Per share($)			
basic	0.30	0.29	+3
diluted	0.30	0.26	+15
Income before tax ($)	916,062	877,621	+4
Net income (loss) ($)	555,840	527,621	+5
Per share($)			
basic	0.13	0.13	+0
diluted	0.12	0.12	+0
Weighted average shares outstanding	4,410,541	4,166,146	+6
Outstanding shares at year end	4,495,250	4,163,250	+8
Capital expenditures ($)	1,569,191	1,059,965	+48
Long term debt, net of working capital ($)	736,745	574,540	+28
After tax rate of return on shareholder equity (%)	44	77	-43
OPERATING			
Gas and oil sales			
Natural gas (Mcf/d)	1,485.8	1,072.4	+39
Natural gas liquids (Bbls/d)	2.7	4.2	-36
Crude oil (Bbls/d)	31.4	37.3	-16
Total (BOE/d) (gas at 6:1)	281.3	220.3	+28
Average sales price			
Natural gas ($/Mcf)	5.06	4.83	+5
Natural gas liquids ($/Bbl)	37.71	33.33	+14
Crude oil ($/Bbl)	19.01	29.60	-36
Total ($/BOE) (gas at 6:1)	29.18	29.18	+0
Reserves (proven and probable)			
Natural gas (Mmcf)	4,455.0	3,444.0	+29
Oil and natural gas liquids (MBbls)	81.8	89.7	-9
Total BOE (MBbls) (gas at 6:1)	824.3	663.7	+24
Undeveloped lands			
Gross	62,022	63,120	-2
Net	10,550	5,666	+86

REPORT TO SHAREHOLDERS

- ♦ Gross revenues up 28%
- ♦ Cash flow up 11%
- ♦ Net income up 5%
- ♦ Shareholder rate of return after-tax 44%
- ♦ Capital expenditures increase 48%
- ♦ Bank debt net of working capital increased by 28%

2001 was a good year for TRAFINA due to a 39% increase in natural gas production as a result of a 100% success rate in drilling 2 Gross (2.0 net) gas wells. The following 2001 highlights point out some of the more significant financial and operational achievements that have contributed to this years results.

2001 HIGHLIGHTS

- ♦ Revenues increased by 28% to $3.0 million, cash flows were up by 11% to $1.34 million, and after tax earnings were up by 5% to $0.56 million over 2000 year-end results. Cash flow per share increased by 3% to 30¢ per share, up from 29¢ in 2000. Earnings remained constant at 13 cents.

- ♦ TRAFINA exited December 2001 at 317 BOE/d, a 2.9% increase over 308 BOE/d in 2000. Average sales during 2001 were 281 BOE/d. Natural gas production increased by 39% to 1,486 Mcf/d in 2001, compared to 1,072 Mcf/d in 2000. Oil and natural gas liquids decreased by 18% to 34 Bbls/d in 2001, from 42 Bbls/d in 2000.

- ♦ During 2001, TRAFINA earned a 44% after-tax rate of return on shareholder equity.

GOING FORWARD

TRAFINA's profits for 2001 were $555,840 after-tax, a 5% increase over 2000. Higher natural gas production has enabled TRAFINA to achieve good operating results as cash flows increased to $1.343 million for year 2001, an 11% increase. This increase in gas production was chiefly produced from our Wetaskiwin area project.

As we go forward we will continue our emphasis on natural gas, increase our land positions in the Wetaskiwin and Jenner areas of Alberta, and continue our emphasis on exploiting our core areas. 88% of our production during 2001 was natural gas.

During 2002 we are planning on drilling five operated wells and four non-operated wells. Drilling programs for our operated wells will commence in the second quarter of 2002 and non operated drilling programs during the first quarter of 2002.

CHANGES

The Company continually monitors decisions and recommendations for the reporting of corporate information as put forward by all Authorities. Accordingly, for the 2001 year all volumes of produced substances reported are actual sales volumes (net of shrinkage and plant fuel) and not wellhead production.

As of December 31, 2000 TRAFINA has adopted that BOE's, (Barrels of Oil equivalent) for natural gas is to be based on a conversion ratio of 6 thousand cubic feet (Mcf) to one Barrel (Bbl).

ACKNOWLEDGMENTS

We are conscious of the support of our shareholders as well as the support of our staff, other stakeholders and clients. We wish to thank them all.

On behalf of the Board,

RValentine

Roland T. Valentine

OPERATIONS REVIEW

During the year 2001, TRAFINA participated in the drilling of 2 wells both of which were Company operated, both of which were drilled at a 100% working interest level and most importantly, both of which were successful gas wells that are currently on production. These wells are located within our central Alberta core exploration and development area at Wetaskiwin. As a result of this success, the Company currently has working interests in four wells capable of gas production in this area.

In southern Alberta at our Jenner gas and oil production project, the corporate consolidations of the original operator Crestar (into Gulf then into Conoco/Philips) delayed several planned field operations. As a consequence, only one pre-existing shut in gas well (TRAFINA 12.5%) was tied into production facilities adding approximately 5 BOE/d to the Company's sales figures. At the time of this writing, one additional oil well (TRAFINA 12.5%) has been drilled and placed into production and a second oil location (also 12.5% net) is being prepared for drilling. The Company anticipates that it will participate in the drilling of 3 to 4 wells in this project area this current year.

Throughout the 2001 sales year TRAFINA continued to grow the proportion of its production base that is operated and controlled by the Company. Statistically, 6% was operated at year end 1999, 35% was operated at year end 2000 and 44% is now operated exiting 2001. With additional Company operated projects in central and southern Alberta, this statistic will continue to increase.

PETROLEUM AND NATURAL GAS SALES

Drilling, re-completion and additional well tie-ins were sufficient to substantially offset production declines experienced in our more mature and non operated projects. As a consequence of these activities, average yearly sales rose 27.7% to 281 BOE/d from the prior year 220 BOE/d. The Wetaskiwin project continued to contribute a substantial portion of product sales averaging 33% over the year increasing to 44% as the Company exited the year with sales of 317 BOE/d.

Year over year sales of natural gas increased 39% from 1,072 Mcf/d to 1,486 Mcf/d demonstrating the Company's focus on natural gas projects. Currently, TRAFINA's sales base is weighted 88% in favour of this clean burning fuel. Minor declines (18%) in oil and liquid sales should be offset in 2002 with the drilling of at least two additional oil locations.

Comparative sales statistics by field for 2001 and 2000 are tabulated below:

Company Share before Royalty

Production by Area	2001	2000	% Change
Natural gas (Mcf/d)			
Bindloss	249	255	(2.4)
Carson Creek	348	406	(14.3)
Jenner	306	268	14.2
Judy Creek	26	43	(39.5)
Wetaskiwin	557	100	457.0
	1,486	1,072 (1)	38.6
Oil & NGL's (Bbls/d)			
Carson Creek	2	2	-
Jenner	31	38	(18.4)
Judy Creek	0	2	(100.0)
Wetaskiwin	1	0	100.0
	34	42	(18.4)
Oil Equivalents (BOE/d) (gas at 6:1)	281	220	27.7

(1) Differences due to rounding.

OIL & GAS RESERVES

During the year 2001, TRAFINA continued to focus on high impact, natural gas reserve projects, the success of which adds significant reserves as well as offsetting and replacing our growing production base. This accomplishment is demonstrated on the following table. Natural gas reserves (proven plus probable) net of sales for the year, increased by 29.4% to 4,455 Mmcf from 3,444 Mmcf in the prior year. Oil and NGL's reserves declined marginally by 8.8% to 81,791 Bbls. In keeping with the prior years 94% ratio of proven to probable reserves, the Company's current ratio is 93.7%.

RESERVES

Company's Interest In Reserves before Royalties

Reserve Category	Oil & NGL's Bbls	Natural Gas Mmcf	Oil Equivalents BOE [1]
Proven and probable (January 1, 2001) [2]	89,710	3,444	663,710
Total proven [3]	62,208	4,259	772,041
Probable (unrisked) [3]	19,583	196	52,250
Proved and probable (January 01, 2002) [3]	81,791	4,455	824,291

(1) *Oil equivalents calculated by TRAFINA using Reliance Engineering Group Ltd. reserve volumes, converting natural gas and natural gas liquids to oil equivalents using conversion ratios of 6.0:1 and 1:0:1 respectively.*

(2) *From an independent reserve appraisal prepared by Reliance Engineering Group Ltd. dated March 12, 2001.*

(3) *From an independent reserve appraisal prepared by Reliance Engineering Group Ltd. dated March 7, 2002.*

TRAFINA's reserves by geographic area are set forth below:

Company's Reserves by Geographic Area

Reserves by Area	Oil & NGL's Bbls	Natural Gas Mmcf	Oil Equivalents BOE [1]	% Total
Proven Reserves				
Bindloss	0	1,225	204,167	26.4
Carson Creek	1,543	343	58,710	7.6
Jenner	57,764	1,032	229,764	29.8
Judy Creek	562	29	5,395	.7
Wetaskiwin	2,339	1,630	274,005	35.5
TOTALS	62,208	4,259	772,041	100.0
Probable Reserves				
Jenner	18,754	30	23,754	45.5
Wetaskiwin	829	166	28,496	54.5
TOTALS	19,583	196	52,250	100.0

RECONCILIATION OF RESERVES

Changes to TRAFINA's proved and probable reserves during the period December 31, 1997 through December 31, 2001 are tabulated below:

Reserve Changes	Oil & NGL's (MBbls)			Natural Gas(Mmcf)		
	Proven	Probable	Total	Proven	Probable	Total
December 31, 1997	45.4	39.3	84.7	3,408	1,791	5,199
Acquisitions/dispositions	0	0	0	0	0	0
Additions/revisions	64.4	-28.2	36.2	1,987	-1,189	798
1998 Production	-5.9	0	-5.9	-454	0	-454
December 31, 1998	103.9	11.1	115.0	4,941	602	5,543
Acquisitions/dispositions	0	0	0	0	0	0
Additions/revisions	-33.8	30.8	-3.0	-615	-406	-1,021
1999 Production	-9.1	0	-9.1	-411	0	-411
December 31, 1999	61.0	41.9	102.9	3,915	196	4,111
Acquisitions/dispositions	0	0	0	0	0	0
Additions/revisions	13.5	-13.7	-0.2	-112	-132	-244
2000 Production	-13.0	0	-13.0	-423	0	-423
December 31, 2000	61.6	28.2	89.7	3,380	64	3,444
Acquisitions/dispositions	0	0	0	0	0	0
Additions/revisions	13.1	-8.6	4.5	1,421	132	1,553
2001 Production	-12.4	0	-12.4	-542	0	-542
December 31, 2001	62.2	19.6	81.8	4,259	196	4,455

Proven oil reserves remained essentially flat for the year 2001 as reserve additions at our Jenner, Alberta property and Wetaskiwin (NGL's associated with gas discoveries) essentially offset the year's production. Probable oil reserves were removed from this category to compensate for a probable drilling location at Jenner that was drilled in early 2002. Accordingly, overall Oil and NGL reserve reductions are approximately 64% of last years production.

After yearly production of 542 Mmcf of gas in the year 2001 and reserve additions from drilling discoveries at Wetaskiwin, Alberta, TRAFINA's year-end proven natural gas reserves are 4,259 Mmcf. An additional minor addition of 132 Mmcf was made to probable reserves reflecting several "behind pipe" zones that have yet to be tested. As a consequence, year-end 2001 natural gas reserves were 4,455 Mmcf.

FUTURE NET CASH FLOWS

Present Values

Based upon the independent appraisal of Reliance Engineering Group Ltd., the before tax present values of TRAFINA's proven plus probable reserves is presented in the table below:

Present Value of Future Net Revenue before Tax

Reserve Class	Undiscounted ($ 000)	10% ($ 000)	15% ($ 000)
Total proven plus probable (January 1, 2001)	11,322	7,778	6,864
Total proven (January 1, 2002)	13,131	8,041	6,866
Probable (unrisked)(January 1, 2002)	615	254	176
Total proven plus probable (January 1, 2002)	13,746	8,285	7,042

Future net revenues is TRAFINA's share of revenues from the sale of hydrocarbon products less royalties, operating costs, future development costs and abandonment and reclamation costs, plus ARTC, but before provision for income taxes, overhead and interest costs. It should not be assumed that the discounted value of estimated future net revenues is representative of the fair market value of the Company's reserves.

COMMODITY PRICE FORECAST

The following table sets forth the escalating price schedule applied to TRAFINA's future oil and gas sales per the Reliance Engineering Group Ltd. engineering report. In anticipation of a possible change to National Policy 2B on Reporting Heavy Oil separately as recommended by the ASC Oil and Gas Task Force (January 24, 2001), TRAFINA is reporting its production and pricing under a heavy oil category due to the volume of heavier crudes that the Company produces. Natural gas pricing reflects the "basket" of gas contracts the Company markets through and any adjustments necessary for the heating content of our various gas production streams.

YEAR	HEAVY OIL $CDN/Bbl	OIL $CDN/Bbl	GAS $CDN/Mcf
2002	19.65	30.40	4.06
2003	21.80	30.80	4.21
2004	24.51	32.15	4.31
2005	26.90	32.90	4.35
2006	28.70	33.70	4.40
2007 (1)	29.50	34.50	4.44

(1) Prices escalated at 1.50 percent per year thereafter.

LAND REVIEW

During 2001, TRAFINA led an aggressive land acquisition strategy in its core areas, primarily in the Wetaskiwin Area. TRAFINA was successful in acquiring a total of 5,920 acres in these core areas, primarily in the Wetaskiwin Area, Alberta. TRAFINA intends on pursuing a progressive strategy for 2002 to aid in the continuing development of our future areas, and with the possibility of entering into joint venture operations to maximize risk management of those assets.

ALBERTA	DEVELOPED		UNDEVELOPED		TOTAL AREA	
	Gross	Net	Gross	Net	Gross	Net
Bindloss	28,160	963	49,120	1,681	77,280	2,644
Carson & Judy Creek	4,320	370	1,280	128	5,600	498
Jenner/Atlee Buffalo	10,082	508	1,282	181	11,364	689
Wetaskiwin	3,700	2,086	8,740	6,960	12,440	9,046
Minor Properties	0	0	1,600	1,600	1,600	1,600
Total (Acres)	46,262	3,927	62,022	10,550	108,284	14,477

CORE AREAS / MAJOR PROPERTIES

OPERATED

WETASKIWIN, ALBERTA

Project Highlights	
Land:	12,440 acres (gross), 9,046 acres (net)
Interests:	Varying working (37.5 – 100%) and royalty
Wells:	5 (gross), 4.5 (net)
Producing Zones:	Belly River, Glauconite, Basal Quartz
Est. Proven Reserves:	1.71 Bcf (gross), 1.63 Bcf (net)
2001 Production:	557 Mcf/d (gross), 557 Mcf/d (net)
2002 Activity:	**Drill between three and four new wells.**

During the 2001 year, the Company's Wetaskiwin property was the central focus of drilling operations, land acquisitions, production increases and proven reserve adds. In this current year, this focus will continue. This core area now represents 44% of our product sales base and 36% of our Corporate proven reserve base. As well, this project now carries almost two thirds of TRAFINA's undeveloped land. Further, the area remains the prospect with immediate drill ready locations and potential production additions. Exit production rates for the 2001 year for this project were 830 Mcf/d or 139 BOE/d.

TRAFINA has highgraded four additional drilling locations at Wetaskiwin that will target multi zones in this exploration and development project. Upwards of three potential reservoir zones are widespread throughout the project area giving the Company exposure to reduced drilling risks and reasonable gas reserve additions. TRAFINA is targeting three main gas bearing reservoirs namely, the Belly River Formation, the Glauconite Formation and the Ellerslie sands.

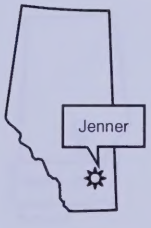
Subsequent to the year end 2001 TRAFINA began gathering and processing its natural gas production through the facilities of AltaGas after the Canadian Natural Bittern Lake West Gas Plant was decommissioned. Operating costs for this processing arrangement are somewhat higher than those costs paid to Canadian Natural however, TRAFINA now has access to both the Nova and the ATCO Transmission systems affording us constant availability of transportation arrangements.

The Company anticipates that additional lands and proprietary seismic will be acquired in the year 2002 and the company will continue to highgrade additional drilling locations for this year and beyond.

OPERATED / NON – OPERATED

JENNER, ALBERTA

Project Highlights	
Land:	11,364 acres (gross), 689 acres (net)
Interests	Varying working (12.5 – 100%) and royalty
Wells:	44 (gross)
Producing Zones:	Milk river, Medicine Hat, Second White Specks, Glauconite and Arcs
Est. Proven Reserves:	Gas: 7.725 Bcf (gross), 1.032 Bcf (net)
Oil & NGL:	567.3 Mstb (gross), 57.8 Mstb (net)
2002 Activity:	**Drill 2 additional horizontal Glauconite oil wells Two possible additional Glauconite gas wells**

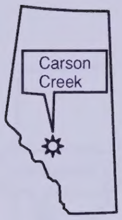


Although surpassed by Wetaskiwin, Alberta as TRAFINA's largest producing property, Jenner remains a pivotal project in terms of long-term oil growth opportunities that will help to balance our production portfolio and multi zone high reserve natural gas opportunities. In the year 2001 oil production declined by 16.2% to 31.4 Bbls/d from 37.0 Bbls/d. This decrease was the result of natural production declines in the Jenner Glauconite "P" pool. TRAFINA had anticipated two additional development wells would have been drilled in the year 2001 however the change of operatorship through corporate combinations delayed this drilling activity until early in the current year. The Company anticipates a return to year 2000 oil production levels or greater once drilling operations have been completed.

Natural gas production increased over the 2001 period as additional reserves were brought on stream and solution gas conservation in the Jenner Glauconite "P" pool was fully implemented.

The Jenner, Alberta project area remains a core area for TRAFINA. As a multi zone gas and oil project the area holds the potential for large reserve additions and the ability to immediately market any discovered product. Geologically, the project is currently being reviewed and since year-end 2001 additional lands for drilling have been added. TRAFINA estimates the Company will participate in a minimum of three wells in this project in the year 2002. Further lands and drilling locations are now being evaluated for immediate action.

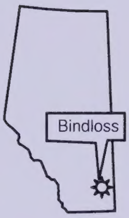
NON - CORE AREAS / MINOR PROPERTIES



CARSON CREEK, ALBERTA

TRAFINA's 10% working interest share of sales gas in this project decreased 145% in the 2001 year from 406 Mcf/d to 348 Mcf/d. The area continues to demonstrate a natural decline in production, a trend the Company anticipates will continue.

At Carson Creek TRAFINA has a 10% working interest in undeveloped acreage that at this time has no proposed drilling location. The Company will continue to evaluate the geological potential of this project with a view to possible expansion of reserve growth and maintenance of facility capacity. TRAFINA currently views this project as a production project.

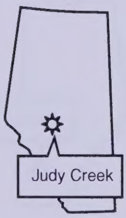


BINDLOSS, ALBERTA

TRAFINA's 3.42% Net Carried Working Interest in the Bindloss Unit No. 1 performed above expectations in the year 2001. Production declined a very modest 2.4% to a net 249 MmcF/d (41.5 BOE/d) from the prior year 255 Mcf/d. In keeping with the above average performance of the Viking gas pool our independent Engineers have increased the Company's reserve share some 12% to 1,225 Mmcf from 1,095 Mmcf in the previous year.

As a superior cash flow producing property, TRAFINA continues to evaluate the area as part of our Southern Alberta core review. The general Bindloss area holds the potential for multi zone Cretaceous reservoirs which are predominantly gas bearing. Facility infrastructure for the gathering and processing of natural gas reserves is in place and currently underutilized.

The Company is also evaluating the possibility to accelerate the reserve recovery from this Viking Pool. Our Engineering suggests a remaining 33 BCF of gas (gross) will be recovered over a 30 year reserve life. Continuing strong natural gas prices indicate very favourable economics for this reserve acceleration.

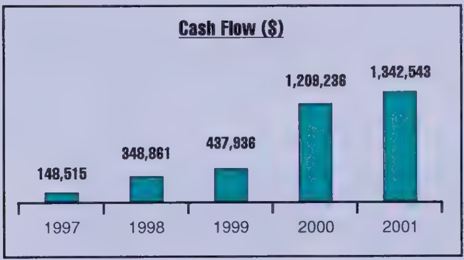


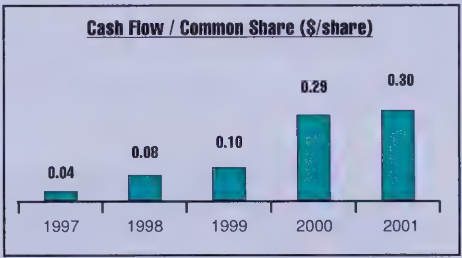
JUDY CREEK, ALBERTA

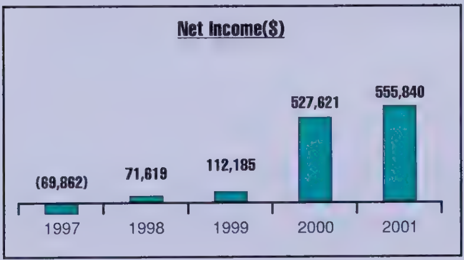
TRAFINA owns a pooled 7.5% working interest in one producing Notikewin gas well in the Judy Creek area of Alberta. Production from this well declined in 2001 to an average 26 Mcf/d (net) from 43 Mcf/d (net) in 2000. As in 2000, the addition of field compression would help to restore former production rates by lowering gathering system entry pressures, however, the economics of that capital expenditure are only marginal for one stand alone well.

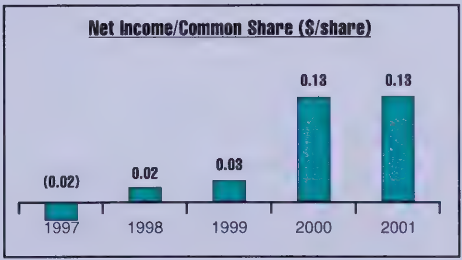
MANAGEMENT'S DISCUSSION & ANALYSIS

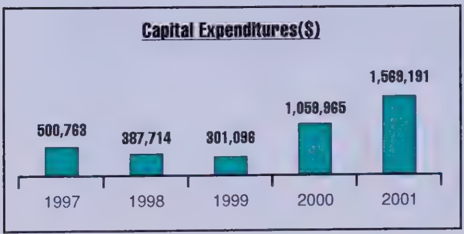
	2001 $	2000 $	% Change
Gross Revenue	3,017,072	2,349,667	+28
Royalties net of ARTC	586,537	404,008	+45
Revenue, net of royalties and ARTC	2,430,535	1,945,659	+25
Operating expenses	353,870	250,542	+41
Cash flow from operations	1,342,543	1,209,236	+11
Cash flow per basic common share	0.30	0.29	+3
per diluted share	0.30	0.26	+15
Income before taxes	916,062	877,621	+4
Net income	555,840	527,621	+5
Net income per basic common share	0.13	0.13	+0
per diluted share	0.12	0.12	+0
Capital expenditures	1,569,191	1,059,965	+48
Long-term debt	738,676	835,836	-12
Working capital	1,931	261,296	-99
Long-term debt, net of working capital	736,745	574,540	+28

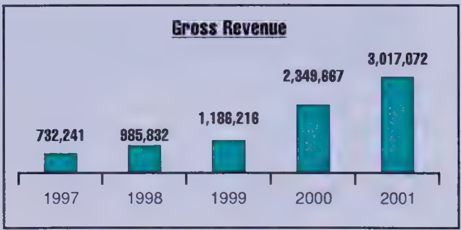












DETAILED FINANCIAL ANALYSIS

PRODUCTION REVENUES

TRAFINA's petroleum and natural gas sales revenue, net of royalties and ARTC, increased 25% to $2,430,535 in 2001 from $1,945,659 in 2000. The increase in production revenues during 2001 was related to increases in natural gas production and yearly averaged gas prices.

ROYALTIES

Total royalties, net of ARTC, increased 45% to $586,537, or $5.70 per BOE in 2001 from $404,008, or $5.03 in 2000 due to increased natural gas production and increased natural gas prices. For the year ended December 31, 2001, TRAFINA has been credited with a $82,469 ARTC rebate compared to $56,347 for the same period in 2000.

Analysis of Royalties

	2001 $	2000 $	% Change
Crown royalty	502,446	320,812	+57
Freehold royalty	91,465	63,343	+44
Overriding royalty	75,095	76,200	-1
Alberta Royalty Tax Credit	(82,469)	(56,347)	+46
Total Royalties	586,537	404,008	+45

OPERATING EXPENSES

Total operating expenses increased 41% to $353,870 to December 31, 2001 as a result of increased costs associated with increased natural gas production, increased NGL production and increased trucking costs.

Analysis of Operating Expenses

	2001 $	2000 $	% Change
Production expenses	340,003	241,927	+41
Lease rental expenses	13,867	8,615	+61
Total operating expenses	353,870	250,542	+41

NETBACKS

TRAFINA's average operating netback decreased 5% to $20.04 per BOE, for the year ended December 31, 2001, from $21.03 per BOE last year. This change is due to increased royalty rate on Crown lands and increased operating costs in the Wetaskiwin area. The following table compares netbacks of 2001 and 2000.

Analysis of Netbacks

	2001 $/BOE	2000 $/BOE	% Change
Sales price	29.18	29.18	+0
Royalties (net of ARTC)	(5.70)	(5.03)	+13
Operating expenses	(3.31)	(3.01)	+10
Lease Rental	(0.13)	(0.11)	+18
Average operating netback	20.04	21.03	-5

GENERAL AND ADMINISTRATION EXPENSES

General and administration expenses, before capitalization, and allocation to a gain on sales of non oil and gas capital assets, increased 56% to $733,178 to December 31, 2001 compared to $468,996 in 2000. On a net basis, general and administration expenses increased 57% to $635,078 to December 31, 2001 compared to $405,207 in 2000. These expenses increased due to increased staffing and salary level and consulting time because of increased activities.

Analysis of General Administrative Expenses

	2001 $/BOE	2000 $/BOE (1)	% Change
Gross General and Administrative	7.13	5.83	+22

BANK CHARGES

Bank charges increased by 16% to $2,468 to December 31, 2001 compared to $2,132 to December 31, 2000 due to an increase of our banking line during 2001.

Analysis of Bank Charges

	2001 $	2000 $	% Change
Bank Charges	2,468	2,132	+16

INTEREST EXPENSES

Interest expense decreased 38% to $39,552 compared to $64,174 in 2000. The weighted average interest rate was 5.0% in 2001, compared to 7.9% in 2000, and interest expense per BOE decreased 53% to $0.38 per BOE from $0.80 per BOE in 2000.

Analysis of Interest Expense

	2001	2000	% Change
Interest expense **($)**	39,552	64,174	-38
Average long-term debt outstanding **($)**	787,256	811,847	-3
Average annual interest rate **(%)**	5.0	7.9	-37
Interest expense **($/BOE)**	0.38	0.80	-53

DEPLETION, DEPRECIATION AND SITE RESTORATION

Depletion and depreciation increased by $136,558, to $480,973 during 2001 from an increase of $115,649 to $344,415 during 2000. On a unit of production basis, in 2001 depletion and depreciation increased to $4.68 per BOE, from $4.28 per BOE in 2000. TRAFINA recorded a $1,300 decrease to $5,000 in site restoration provisions, for 2001, compared to an decrease of $2,300 to $3,700 in 2000.

Analysis of Depletion, Depreciation and Site Restoration

	2001	2000	% Change
Depletion and depreciation **($)**	485,973	344,415	+40
Site restoration **($)**	5,000	3,700	-35
Depletion and depreciation **($/BOE)** (gas at 6:1)	4.68	4.28	+9
Site restoration **($/BOE)** (gas at 6:1)	0.05	0.05	+0

INCOME TAXES

Available tax pools after December 31, 2001 were $1,014,000 compared to $759,000 in 2000. Current income taxes were $49,889 for 2001. The Corporation anticipates it will be taxable in 2002. Future taxes increased by $310,333 to $1,124,833 during 2001, compared to an increase of $333,500 to $814,500 in 2000.

Analysis of Income Taxes

	Deduction Rate	2001 $	2000 $
Canadian exploration expense	100%	0	0
Canadian development expense	30%	181,175	202,500
Canadian oil and gas property expense	10%	315,825	76,900
Undepreciated capital cost allowance	20% - 30%	517,000	479,600
Available tax pools		**1,014,000**	**759,000**

CASH FLOW FROM OPERATIONS

In 2001, cash flow from operations increased 11% to $1,342,543 up from $1,209,236 in 2000. This gain translated to $0.30 per diluted common share, a 15% improvement over the $0.26 per diluted common share recorded in 2000. Cash flow increases are a result of increased production of natural gas and increases in the prices of natural gas

EARNINGS

TRAFINA's 2001 net earnings were $555,840, a 5% increase over the $527,621 recorded in 2000. On a diluted per share basis, the 2001 net earnings remained the same at $0.12 in 2001 and 2000. On a per-unit of production basis, 2001 earnings decreased by 18% to $5.40/BOE, compared to $6.56/BOE in 2000.

RETURN OF EQUITY

TRAFINA's after-tax return on shareholder's equity decreased in 2001 to 44% compared to 77% in 2000, a decrease of 43%.

BANK DEBT AND LIABILITY

TRAFINA has a total credit line of $2.0 million of which $738,676 was drawn at December 31, 2001. Current assets plus the unused portion of our advances exceed our current liabilities by 2.9 times. Cash flow of $1,342,543 exceeds our 2001 annual interest payments by 34 times (2001 interest charges were $39,552). TRAFINA's debt to equity ratio at year-end 2001 is 0.65 times, at December 31, 2001, compared to 1.09 times debt equity ratio in 2000.

NET ASSET VALUE

TRAFINA's net asset value at year-end 2001 $1.81 per share diluted compared to $1.58 diluted in 2000. These values have been calculated using a third party independent engineering report for each year and an estimate from management of the undeveloped lands, facilities, pipelines and seismic.

Analysis of Net Asset Value

(Discounted at PV 10% escalating price.)	2001 ($000)	2000 ($000)	% Change
Proven reserves	8,041	7,387	+3
Probable reserves (risked at 50%)	127	196	-35
Undeveloped land & other assets (estimated by management)	685	275	+357
Working capital	2	261	-99
Long-term debt	(739)	(836)	-12
Total net asset value	**8,116**	**7,283**	**+11**
Asset value per outstanding share	1.81	1.75	+0
Asset value per diluted share	1.81	1.58	+9

LIQUIDITY AND CAPITAL RESOURCES

TRAFINA historically has relied upon two sources of funding to support its capital expenditure programs.

These sources are as follows:

1. Internally generated cash flow; and

2. Bank debt to be used when deemed appropriate. TRAFINA has maintained a conservative policy concerning the use of bank debt.

In 2001 TRAFINA financed its capital expenditures of $1,569,191 from its cash flow of $1,342,543 and the balance financed by bank debt.

SENSITIVITIES

The following table sets out the annualized sensitivities of TRAFINA's cash flow per share to changes in the prices of crude oil and natural gas, and changes in the production of crude oil and natural gas. These estimated sensitivities have no provisions for any capital requirements and other costs to arrive at each estimated cash flow per share.

Change of	Operating Netback Amount ($)	Cash Flow Per Share ($/share)
$1.00/Mcf natural gas	250,776	0.06
$1.00/Bbl	5,762	0.00
1 Mmcf/d natural gas	538,826	0.12
10 Bbl/d crude oil	23,592	0.01

IMPACT OF NEW ACCOUNTING PRONOUNCEMENTS

Stock-Based Compensation Plans

The Accounting Standards Board of the Canadian Institute of Chartered Accountants ("CICA") has recently approved new standards for accounting for stock options and other stock-based compensation plans. The rules parallel those in the United States and may require Canadian companies to measure and record compensation expense for employee stock options in many circumstances. The Company would incur compensation expense for any individuals that are granted options and are not employees of the Company (issued a T-4). This rule will exclude directors if the options were issued for compensation of being a director. In addition, re-pricing or other modification of terms or options to non-employees will result in compensation expenses in most circumstances.

In addition, the Company will be required to measure all stock awards granted subsequent to January 1, 2002 at fair value using an option-pricing model in order to present pro-forma earnings and earnings per share amounts in the notes to the consolidated financial statements.

The Company has not yet determined the impact this new pronouncement will have on the Company's future financial statements.

Long Term Debt

The Emerging Issues Committee of the Canadian Institute of Chartered Accounts ("CICA") pronouncement "Balance Sheet Classification of Callable Debt Obligations and Debt Obligations Expected to be Refinanced" may impact the corporation beginning in the first quarter of 2002. Under this pronouncement, some debts previously classified as long-term will now be classified as current liabilities, including demand debt with repayment terms.

The Company has not yet determined the impact this new pronouncement will have on the Company's future financial statements.

HISTORICAL QUARTERLY FINANCIAL INFORMATION

Outlined below is a table of the historical quarterly financial information based on past reported results over the last five years 1997 to 2001 inclusive. The treasury stock method has not been used in calculating the quarterly diluted earnings per share and the quarterly diluted cash flow per share shown immediately below.

Quarterly Financial Information (unaudited)

2001	1Q	2Q	3Q	4Q
Oil and gas revenue	1,277,524	614,677	580,249	528,518
Cash flow per basic common share	0.13	0.08	0.05	0.04
per diluted share	0.13	0.08	0.04	0.05
Net income per basic common share	0.08	0.08	0.03	(0.06)
per diluted common share	0.08	0.08	0.03	(0.07)
2000	**1Q**	**2Q**	**3Q**	**4Q**
Oil and gas revenue	309,669	516,214	554,784	965,666
Cash flow per basic common share	0.03	0.06	0.06	0.14
per diluted share	0.03	0.06	0.05	0.12
Net income per basic common share	0.00	0.03	0.03	0.07
per diluted common share	0.00	0.03	0.03	0.06
1999	**1Q**	**2Q**	**3Q**	**4Q**
Oil and gas revenue	248,622	251,611	321,656	360,465
Cash flow per basic common share	0.02	0.02	0.03	0.04
per diluted share	0.02	0.01	0.03	0.04
Net income per basic common share	0.00	0.00	0.01	0.01
per diluted common share	0.00	0.00	0.01	0.01
1998	**1Q**	**2Q**	**3Q**	**4Q**
Oil and gas revenue	211,737	240,097	239,823	363,993
Cash flow per basic common share	0.01	0.02	0.01	0.04
per diluted share	0.01	0.02	0.01	0.03
Net income per basic common share	0.00	0.00	(0.01)	0.04
per diluted common share	0.00	0.00	(0.01)	0.03
1997	**1Q**	**2Q**	**3Q**	**4Q**
Oil and gas revenue	203,321	130,885	182,984	215,051
Cash flow per basic common share	0.01	0.01	0.00	0.02
per diluted share	0.01	0.01	0.00	0.02
Net income per basic common share	0.00	(0.01)	(0.01)	0.00
per diluted common share	0.00	(0.01)	(0.01)	0.00

MANAGEMENT'S REPORT

The financial statements of TRAFINA Energy Ltd., were prepared by management in accordance with accounting principles generally accepted in Canada. The financial and operating information presented in this annual report is consistent with that shown in the financial statements.

Management has designed and maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of financial statements for reporting purposes. Timely release of all financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgments made by management.

External auditors appointed by the shareholders have conducted an independent examination of the corporate accounting records in order to express their opinion of the financial statements.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through its Audit Committee. The Audit Committee, consisting of a majority of non-management directors has met with the external auditors and management in order to determine that management has fulfilled its responsibilities to the preparation of the financial statements. The Audit Committee has reported its findings to the Board of Directors who have approved the financial statements.

Donald J. Douglas
Chairman, Audit Committee

Roland T. Valentine
Member, Audit Committee

AUDITOR'S REPORT

To the Shareholders of
TRAFINA Energy Ltd.

We have audited the balance sheets of TRAFINA Energy Ltd. as at December 31, 2001 and 2000 and the statements of income and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2001 and 2000 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP
Chartered Accountants

Calgary, Canada
March 13, 2002

FINANCIAL STATEMENTS

BALANCE SHEETS
AS AT DECEMBER 31, 2001 AND 2000

	2001	2000
ASSETS		
Current assets		
Accounts receivable	$ 270,626	$ 663,842
Alberta royalty tax credit receivable	82,472	56,350
Income taxes receivable	54,611	0
Prepaid expenses	35,996	26,251
	443,705	746,443
Capital assets (note 2)	3,702,676	2,629,458
	$ 4,146,381	$ 3,375,901
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 441,774	$ 485,147
Long-term debt (note 3)	738,676	835,836
Site restoration provision (note 2)	35,080	30,080
Future income taxes (note 5)	1,124,833	814,500
	2,340,363	2,165,563
Shareholders' Equity		
Share capital (note 4)	353,256	313,416
Retained earnings	1,452,762	869,922
	1,806,018	1,210,338
	$ 4,146,381	$ 3,375,901

See accompanying notes to financial statements.

On behalf of the Board of Directors:

Director

Director

STATEMENTS OF INCOME & RETAINED EARNINGS

	2001	2000
REVENUES		
Oil and gas sales	$ 3,000,967	$ 2,346,333
Royalties, net of ARTC	(586,537)	(404,008)
Gain on sale of capital assets	9,603	0
Interest and other	6,502	3,334
	2,430,535	1,945,659
EXPENSES		
Operating	353,870	250,542
General and administration	635,078	405,207
Depletion and depreciation	480,973	344,415
Interest	39,552	64,174
Site restoration	5,000	3,700
	1,514,473	1,068,038
Income before income taxes	916,062	877,621
Provision for income taxes (note 5)		
Current	(49,889)	(16,500)
Future	(310,333)	(333,500)
	(360,222)	(350,000)
Net income for the year	555,840	527,621
Retained earnings, beginning of year	896,922	373,909
Redemption of common shares	0	(4,608)
Retained earnings, end of year	$ 1,452,762	$ 896,922
Net income per share		
Basic	$ 0.13	$ 0.13
Diluted	$ 0.12	$ 0.12

See accompanying notes to financial statements.

STATEMENTS OF CASH FLOWS

YEARS ENDED DECEMBER 31, 2001 AND 2000

	2001	2000
CASH PROVIDED BY (USED IN) :		
OPERATIONS:		
Net income	$ 555,840	$ 527,621
Items not involving cash:		
Depletion, depreciation and site restoration	485,973	348,115
Gain on sale of capital assets	(9,603)	0
Future income taxes	310,333	333,500
Cash flow from operations	1,342,543	1,209,236
Change in non-cash operating working capital (note 6)	259,365	(190,759)
	1,601,908	1,018,477
FINANCING:		
Issuance of common shares	39,840	0
Repurchase and cancellation of common shares	0	(6,490)
Increase (decrease) in long-term debt	(97,160)	47,978
	(57,320)	41,488
INVESTING:		
Proceeds of sale of capital assets	24,603	0
Additions to capital assets	(1,569,191)	(1,059,965)
	(1,544,588)	(1,059,965)
Net change in cash	0	0
Cash beginning of year	0	0
Cash end of year	$ 0	$ 0
Cash flow from operations per share (note 4)		
Basic	$ 0.30	$ 0.29
Diluted	$ 0.30	$ 0.26

See accompanying notes to financial statements.

1. SIGNIFICANT ACCOUNTING POLICIES

CAPITAL ASSETS

TRAFINA Energy Ltd. (the "Corporation") follows the full cost method of accounting for its oil and gas operations. All costs related to the acquisition of and exploration for petroleum and natural gas interests are capitalized. Such costs include land and lease acquisition costs, geological and geophysical costs, costs of drilling and equipping productive and non-productive wells and capitalized general and administration costs reasonably allocated to these activities.

Proceeds from disposals are recorded as a reduction of the related expenditures without recognition of a gain or loss unless the disposal would result in a change of 20% or more in the depletion rate.

Capitalized costs are depleted and depreciated using the unit-of-production method based on the estimated proven reserves of oil and gas before royalties, as determined by independent engineers. For purposes of the depletion and depreciation calculation, natural gas reserves are converted to a petroleum equivalent unit at a rate of six thousand cubic feet of natural gas to one barrel of crude oil.

The Corporation applies a ceiling test to ensure that capitalized costs do not exceed estimated future net revenues from production of proven reserves at year end prices plus the costs of unproven properties net of impairment allowances, less future production, capital costs, administrative, financing, site restoration and income tax costs.

Office equipment is depreciated using the declining balance method at an annual rate of 20%.

SITE RESTORATION

Estimated future site restoration costs are provided for using the unit-of-production method based on estimated proven reserves. The annual charge is accounted for as an expense and the accumulated provision is accrued as a liability. Actual site restoration costs are deducted from the accumulated provision in the year incurred.

JOINT OPERATIONS

The majority of the oil and gas operations of the Corporation are conducted jointly with others and accordingly these financial statements reflect only the proportionate interest of the Corporation in such activities.

USE OF ESTIMATES

The amounts recorded for depletion and depreciation of oil and gas properties and for site restoration are based on estimated reserves and future costs. By their nature, these estimates, and those related to the future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

FINANCIAL INSTRUMENTS

The Corporation may enter into derivative instrument contracts to manage its exposure related to oil and gas prices. Settlement amounts on commodity hedge contracts are recognized in earnings as the related production revenues are recorded.

INCOME TAXES

The Corporation follows the liability method of accounting for income tax (note 5). Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respected tax bases using enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

STOCK BASED COMPENSATION PLAN

The Corporation has a stock option plan, which is described in note 4. No compensation expense is recognized for this stock option plan when stock options are issued. Any consideration paid on the exercise of stock options is credited to share capital.

PER SHARE AMOUNTS

Effective January 1, 2001 the Corporation retroactively adopted the new standard for the computation, presentation and disclosure of earning per share. Under the new standard, basic per share amounts are calculated using the weighted average number of common shares outstanding during the year. Diluted per share amounts are calculated using the treasury stock method instead of imputed earnings method to determine the dilutive effect of stock options and other dilutive instruments.

2. CAPITAL ASSETS

December 31, 2001	Cost	Accumulated Depletion & Depreciation	Net Book Value
Oil and gas properties	$ 4,196,685	$ 1,292,256	$ 2,904,429
Production equipment	1,126,099	388,688	737,411
Office equipment	140,281	79,445	60,836
	$ 5,463,065	$ 1,760,389	$ 3,702,676

December 31, 2000	Cost	Accumulated Depletion & Depreciation	Net Book Value
Oil and gas properties	$ 2,839,382	$ 920,370	$ 1,919,012
Production equipment	921,850	293,671	628,179
Office equipment	132,642	65,375	67,267
Other	15,000	0	15,000
	$ 3,908,874	$ 1,279,416	$ 2,629,458

During the year ended December 31, 2001, general & administrative costs of approximately $98,000 (2000 - $64,000) were capitalized pertaining to the Corporation's exploration costs, development and property acquisition programs. At December 31, 2001 total estimated future site restoration costs to be accrued over the remaining life of proven reserves are approximately $117,000. During the years ended December 31, 2001 and 2000 the Corporation included the cost of unproven properties in the depletion and depreciation calculations. At December 31, 2001 total future proven development costs of approximately $615,000 (December 31, 2000 $91,000) were included in the depletion and depreciation calculations.

3. LONG TERM DEBT

The Corporation has a demand revolving operating credit facility with a Canadian chartered bank under which it can borrow up to $2,000,000. The facility bears interest at the bank's prime rate plus one percent per annum. The loan is secured by a floating charge demand debenture in the amount of $3,000,000 over the Corporation's capital assets and a general assignment of book debts.

The revolving operating credit facility revolves until May 31, 2002 at which time the facility shall be converted to a term facility with a term, at the bank's discretion, not to exceed five years. The bank has indicated that, while it reserves the right to request payment on demand, no principal payments are required prior to January 1, 2003 and the revolving credit facility will continue in the future provided the Corporation satisfies the conditions of the loan agreement.

4. SHARE CAPITAL

AUTHORIZED
Unlimited number of Class A voting common shares;
Unlimited number of Class B non-voting common shares; and
Unlimited number of preferred shares issuable in series.

ISSUED

Class A Common Shares	2001 # of shares	2001 Amount	2000 # of shares	2000 Amount
Balance, beginning of year	4,163,250	$ 313,416	4,188,250	$ 315,298
Repurchased and cancelled			(25,000)	(1,882)
Stock options exercised	332,000	$ 39,840	0	0
Balance, end of year	4,495,250	$ 353,256	4,163,250	$ 313,416

OPTIONS

The Corporation has an employee stock option plan under which employees, directors and consultants are eligible to receive grants. On December 31, 2001, 105,000 Class A common shares were reserved for issuance under the plan. Options under the plan have a term of three years to expiry. The exercise of each option equals the issuer price of the Corporation's common shares on the day before the date of the grant.

	2001 Number of Options	2001 Exercise Price	2000 Number of Options	2000 Exercise Price
Stock option outstanding beginning of year	437,000	$ 0.12	437,000	$ 0.12
Exercised	(332,000)	0.12	0	$ 0
Stock option outstanding end of year	105,000	$ 0.12	437,000	$ 0.12
Exercisable at year end	105,000	$ 0.12	437,000	$ 0.12

The stock options outstanding and exercisable at December 31, 2001 have a remaining contractual life of 0.32 years.

PER SHARE AMOUNTS

The following table details information regarding per share amounts:

	2001	2000
Weighted average number of common shares	4,410,541	4,166,146
Dilutive effect of stock options	76,552	386,145
Fully diluted net income per share under the imputed earnings method	$0.12	$0.12
Fully diluted cash flow per share under the imputed earnings method	$0.30	$0.26

5. INCOME TAXES

Effective January 1, 2001, the Corporation retroactively adopted the liability method of accounting for income taxes. Prior year's financial statements have not been restated for the change. The effect of the change was to increase future income taxes by $60,000 and decrease retained earnings by $60,000.

The provision for income taxes differs from the amount that would have been expected by applying the corporate income tax rate to income before taxes. The principal reasons for these differences are as follows:

	2001	2000
Income before taxes	$ 916,062	$ 877,621
Statutory income tax rate	42.60%	44.62%
Anticipated tax provision	390,242	391,594
Increase (decrease) in income tax resulting from		
Non-deductible payments	221,956	143,082
Alberta royalty tax credit	(35,131)	(25,142)
Change in enacted income tax rate	(34,975)	0
Resource allowance	(185,962)	(164,695)
Other	4,092	5,161
Income taxes	$ 360,222	$ 350,000

The components of the future income tax liability at December 31, 2001 and 2000 are as follows:

	2001	2000
Future income tax liability		
Capital assets	$ 1,136,033	$ 824,500
Future income tax assets		
Site restoration	(11,200)	(10,000)
	$ 1,124,833	814,500

The Corporation has available for deduction against future taxable income tax deductions aggregating approximately $1,014,000 (2000 - $759,000).

6. SUPPLEMENTAL CASH FLOW DISCLOSURE

	2001	2000
Accounts receivable	$ 393,216	$ (524,270)
Alberta royalty tax credit receivable	(26,122)	(26,385)
Income taxes receivable	(54,611)	0
Prepaid expenses	(9,745)	(16,783)
Accounts payable	(43,373)	376,679
	$ 259,365	$ (190,759)

The following net cash payments were made:

	2001	2000
Interest paid	$ 39,552	$ 64,174
Income taxes paid	$ 110,000	$ 16,500

7. FAIR VALUES

As at December 31, 2001, there are non-significant differences between the carrying amount of accounts receivable, accounts payable and accrued liabilities and long term debt and their estimated market values.

FIVE YEAR HISTORICAL SUMMARY

	2001	2000	1999	1998	1997
Financial					
Oil and Gas Revenue	$ 3,000,967	$ 2,346,333	$ 1,186,216	$ 1,055,650	$ 732,241
Cash Flow from operations	$ 1,342,541	$ 1,209,236	$ 437,936	$ 348,861	$ 148,515
Per share basic	$ 0.30	$ 0.29	$ 0.10	$ 0.08	$ 0.04
Per share diluted	$ 0.30	$ 0.26	$ 0.09	$ 0.07	$ 0.04
Net income before tax	$ 916,062	$ 877,621	$ 203,170	$ 131,619	$ (61,582)
Net income (loss)	$ 555,840	$ 527,621	$ 112,185	$ 71,619	$ (69,862)
Per share basic	$ 0.13	$ 0.13	$ 0.03	$ 0.02	$ 0.02
Per share diluted	$ 0.12	$ 0.12	$ 0.02	$ 0.02	$ 0.02
Capital expenditures	$ 1,569,191	$ 1,059,965	$ 301,096	$ 387,714	$ 500,763
Total assets	$ 4,146,381	$ 3,375,901	$ 2,092,913	$ 2,057,110	$ 1,782,040
Long-term debt	$ 738,676	$ 835,836	$ 787,858	$ 812,089	$ 759,949
Working capital	$ 1,931	$ 261,296	$ 70,537	$ 96,911	$ (18,949)
Shareholders' equity	$ 1,806,018	$ 1,210,333	$ 749,207	$ 679,094	$ 620,762
Common shares outstanding					
Weighted average-basic	4,410,541	4,166,146	4,310,586	4,431,969	4,510,820
Weighted average-diluted	4,487,063	4,552,291	4,747,586	4,884,969	4,776,414
At year end	4,495,250	4,163,250	4,188,250	4,379,250	4,511,250
Share trading price					
High	$ 0.75	$ 0.40	$ 0.25	$ 0.23	$ 0.39
Low	$ 0.29	$ 0.16	$ 0.12	$ 0.10	$ 0.20
Close	$ 0.40	$ 0.25	$ 0.12	$ 0.23	$ 0.29
Volume of shares traded (total)	349,500	328,000	413,249	602,749	657,501
Year-end stock market capitalization	$ 1,798,100	$ 1,040,813	$ 502,590	$ 1,007,228	$ 1,308,263
Diluted net asset value					
per share (at 10% pre-tax)	$ 1.81	$ 1.58	$ 0.83	$ 0.92	$ 0.69
Return on average equity (%)	44.0	77.0	28.0	19.4	(9.9)
	2001	2000	1999	1998	1997
Operating					
Natural gas sales (mcfd)	1,485.8	1,072.4	1,127.0	1,243.0	1,022.0
Natural gas liquids sales (Bbls/d)	2.7	4.2	7.1	4.0	1.7
Crude oil sales (Bbls/d)	31.4	37.3	17.7	12.0	9.0
Total Sales (BOE/d)	281.3	220.3	212.6	140.0	113.0
Average sales price					
Natural gas ($/Mcf)	5.06	4.83	2.45	2.20	1.84
Natural gas liquids ($/Mcf)	37.71	33.33	16.53	13.70	26.71
Crude oil ($/Bbl)	19.01	29.60	20.32	12.14	18.08
Total ($/BOE) (gas at 6:1)	29.18	29.18	15.23	20.90	18.46
Operating netback ($/BOE) (gas at 6:1)	20.04	21.03	10.46	8.19	5.82
Wells drilled (gross (net))					
Gas an Oil Completions	2(2.0)	4(1.35)	1(0.13)	8(0.31)	3(0.17)
Dry and abandoned	0	1(0.10)	1(0.13)	2(0.13)	1(0.10)
TOTAL	2(2.0)	5(1.45)	2(0.26)	10(0.44)	4(0.27)
Natural gas reserves (mmcf)					
Proven	4,259	3,380	3,915	4,941	3,408
Probable	196	64	196	602	1,791
Oil and NGL Reserves (MBbls)					
Proven	62.2	61.6	61.0	103.9	45.4
Probable	19.6	28.2	41.9	11.1	39.3
TOTAL BOE	824,291	663,800	788,067	1,038,833	951,200
Present value at 10% pre-tax ($M)	$ 8,286	$ 7,778	$ 4,502	$ 5,367	$ 4,637
Finding and on-stream cost ($/BOE)	$ 8.37	(1)	(1)	(1)	(1)
Undeveloped land (net acres)	10,550	5,666	5,058	2,818	(1)

(1) Not Reported

NOTES

TRAFINA
ENERGY LTD.

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STOCK LISTING CDNX
Symbol: TFA.A

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Several statements in this annual report including statements regarding oil and gas production, reserves or other oil and gas activities, are forward looking. These forward-looking statements are based on TRAFINA's current expectations. Because forward-looking statements involve risks and uncertainties, TRAFINA's actual results could differ materially.

TRAFINA Energy Ltd. is listed for trading on the Canadian Venture Stock Exchange and is engaged in the acquisition, exploration, development and production of oil and natural gas in Alberta. The Canadian Venture Stock Exchange has neither approved nor disapproved the information contained herein.

TRAFINA

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